BEFORE THE
ILLINOIS COMMERCE COMMISSION

IN THE MATTER OF:)
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ELECTRIC POLICY MEETING)
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)

Chicago, Illinois
May 8, 2002

Met pursuant to notice at 1:30 p.m.

BEFORE:

COMMISSIONER HARVILL
COMMISSIONER MATHIAS
COMMISSIONER KRETSCHMER
COMMISSIONER SQUIRES
COMMISSIONER HURLEY

SULLIVAN REPORTING COMPANY, by
Kathleen Maloney, CSR, RPR

COMMISSIONER HARVILL: Good afternoon. This is a special open meeting convened, an electric policy meeting. Present today in Chicago are Commissioner Kretschmer, Commissioner Mathias, Commissioner Squires, Commissioner Hurley and myself, Commissioner Harvill.

Today representatives of Central Illinois Light Company, Illinois Power Company and Commonwealth Edison will set demand forecasts for summer and answer questions from the Commissioners regarding the status of the repair and upgrade efforts of their respective utility distribution facilities.

Each representative will have 15 minutes for his or her presentation. At the conclusion of each presentation, we will have questions or comments from the Commissioners.

I will note bonus points will be given for brevity.

If there are any questions --

COMMISSIONER SQUIRES: I will second that.

COMMISSIONER HARVILL: Are there any questions or comments from the Commissioners before we begin?

That being said, the order of presentations today is we are going to hear first Scott Cisel, senior vice president for the Central Illinois Light Company followed by Ameren, MidAmerican, Illinois Power and Commonwealth Edison.

And with that, I will turn things over to Mr. Cisel.

MR. CISEL: Thank you.

And the way I was able to get through college was to take all the bonus points I could. So I will listen very carefully to brevity.

I presume everyone has received a copy of our presentation for today.

And what I think I'll do, in consideration of everyone's time, is hit the highlights, and perhaps we'll begin with the first page titled Summary.

And the summary page in particular encapsulates the entire situation for Central Illinois Light Company.

If you look at the bar graph, expected

peak of the year 2002 is 1,228 megawatts. Following the conditions and requirements presented by the Commission in trying to forecast the worse-case scenario for Central Illinois Light Company, the forecast demand was 1,294 megawatts.

And when you look at the total resources available to CILCO based upon what we own, the customer resources and contracted purchases, the total availability for our system is 1,460 megawatts.

When you look on an individual, case-by-case situation on a month-by-month basis for June, July and August of this year, the forecasted upgrade reserve for our company varies between 22 percent and 29 percent also following the requirement to making an assessment of whether or not any of the CILCO transmission facilities, sub-transmission lines, distribution feeders and/or substation transformers are in the situation in which they are loaded at 100 or greater, we find no circuits or distribution systems that will exceed that level of occurrence.

That would be an overview.

I am certainly willing to go into the pages behind because there is detail that supports the summary.

I really look to the Commissioners if you would like for me to go page by page and hit a highlight, or if you would rather stop and just ask questions, I will follow your lead.

COMMISSIONER KRETSCHMER: I wouldn't mind hearing you go page by page hitting the highlights.

MR. CISEL: Okay. I will follow your suggestion. Thank you.

Turning to the second page, Expected Peak Summer Load, as already presented in the summary, we indicate it's going to be 1,228 megawatts.

We identify the model that we use which includes the variables of weather, economic growth, et cetera.

I think a very important aspect to identify with CILCO, of the total megawatt retail sales that we have for the commercial and industrial market segments, half of the expected load we learn of by meeting and visiting with our customers about their plans as far as usage, production, extension, regression, et cetera.

So a good percent of our forecast is based upon individual interviews with our commercial and industrial customers.

Turning to the next page entitled Possible Worse-case Expected Peak Summer Load, we identified the worse-case scenario based upon the inputs of looking back for the past 30 years including temperature and humidity of the worse scenario. We come up with the scenario projecting 1,294 megawatts would be the forecasted demand, peak demand, under this particular scenario.

Turning to the next page entitled 2002 Expected Resources, this page presents, if you will, the resources that CILCO owns. It also identifies the various inputs from generation to interruptible load that we receive from customers as well as contracted purchases.

In general the resources that CILCO owns and operates is about 80 percent of the total.

About 13 percent of the megawatts listed are provided through contracted purchases where we have firm transmission delivery acquired for the supply and the remaining 7 percent is represented from customers who will either respond to an interruptible period by either shedding load or putting on on-schedule generation.

Turning to the next page entitled Transmission System Reliability, once again in this particular scenario, no transmission facilities are anticipated to be loaded above the 100 percent level during either the expected or worse-case peak. It identifies various contingencies that have been run to support this claim.

CILCO is a very contiguous system. We are highly integrated and very close range. Just due to our size and load configuration, we cannot in any case provide any cascading outages for the interconnected system.

Going to the page titled Sub-transmission, Substation and Feeder Reliability, again this is focusing on the sub-transmission lines, distribution feeder, substation transformers, not to be loaded at a percent of 100 or greater during this time.

The final point on this page identifies that we did not do a worse-case loading conditions.

You can develop any scenario that you want such as the very large customer would build on an end of line. Certainly in that scenario, that circuit would be overloaded. But in that particular situation, we would upgrade the system based upon the anticipated usage by that customer or growth by those particular customers on that distribution circuit.

The next page, not really titled, but it compares our forecasted system peak of 2001 versus actual system peak. The difference there is 7 megawatts.

Our actual demand compared to our forecasted demand was within one-half of a percent.

The next page entitled Schedule Maintenance May 15 through September 15, 2002. The two peaking units that we have are scheduled for maintenance. We already started maintenance of one of those two units.

There were no indications that either one of the units wouldn't be ready to respond by the end of June or by the end of May.

The last handout sheet, Adequate Supply to Customers' loads, as you probably know, CILCO is a member of MISO. We are participating under a MISO arrangement at this particular time.

That became effective and operational January 1st of this year.

At this time I would say that we are going through a new phase and learning through the various scenarios, but we are participating under the direction of MISO.

With that, I hope it was brief enough that a point or two was given to me as a bonus, and I would respond to any questions or comments you might have.

COMMISSIONER HARVILL: Are there questions from the Commissioners?

COMMISSIONER KRETSCHMER: I do have one question.

Noticing the amount of operating reserve you have, better than 20 percent, do you have any interruptible customers?

MR. CISEL: Yes, we do, Commissioner. We have about 5 percent of our expected resources are reflected by interruptible customers.

COMMISSIONER KRETSCHMER: In the past year, have you interrupted them?

MR. CISEL: We certainly have at particular times. Those particular times would be if we had scheduled maintenance in one of our units, and based upon price in the market, we would call an interruption in the customers.

COMMISSIONER KRETSCHMER: In the normal course of events with that kind of reserve margin, is there a possibility that your interruptible customers are simply not paying their fair share receiving firm service instead of being interrupted?

MR. CISEL: In our interruptible contracts, we have a provision to mandate interruption due to system reliability or security as well as we can interrupt for economic purposes where we can share.

COMMISSIONER KRETSCHMER: How often do you interrupt?

I just have a feeling that sometimes certain customers get firm service and pay for standby or interruptible.

MR. CISEL: In our individual contracts, we can interrupt 400 hours per every 12 months.

MS. KRETSCHMER: But do you do it?

MR. CISEL: Yes. Last year our average was about 225 hours of actual interruption.

COMMISSIONER KRETSCHMER: Per customer?

MR. CISEL: Yes. That's correct.

MS. KRETSCHMER: Thank you.

MR. CISEL: You are welcome.

COMMISSIONER HARVILL: Are there other questions?

COMMISSIONER MATHIAS: Just two.

When you say that you have third-party sources for power, are these take-a-pay contracts generally?

MR. CISEL: No. These are firm contracts we've entered into for supply and capacity for firm transmission security.

COMMISSIONER MATHIAS: If you had unhedged prices, what do you see -- unhedged opportunities, where do you see some of our prices going by month?
In other words, what do you expect prices to do in the marketplace for delivery in June, July and August?
MR. CISEL: Of this year?
If you look at the forward curves that are available today, depending upon the particular month, they range today 50 to $65 per megawatt hour. Then you also have to consider the transmission get to the supply to CILCO service territory. It's generally depending upon your source another $5.
COMMISSIONER MATHIAS: So 50 to $70?
MR. CISEL: Per megawatt hour. I am speaking of on-peak time.
COMMISSIONER MATHIAS: Compared to last year?
MR. CISEL: Last year was a softer market for us. Probably comparison of a price in the 40 to $45 range.
COMMISSIONER MATHIAS: And when you say your system, transmission system, is not loaded to 100

percent in the anticipated peak or worse case, where would you be as far as the loading of the transmission facilities with regards to the expected peak in the worse case?

MR. CISEL: In the expected peak scenario, depends upon which circuit it is. Generally it's probably in the 50 to 60 percent range.

In the worse-case scenario, then it depends which circuit you are looking at in particular.

I believe the worse-case scenario, circuit was pressing about 90 percent.

COMMISSIONER MATHIAS: And in the expected peak scenario, what would the worse case be?

MR. CISEL: In the expected worse case?

COMMISSIONER MATHIAS: In the two scenarios, one is the expected and the other is the worse case.

What would the transmission loading maximum amount be for the circuit in the anticipated?

MR. CISEL: About 60 percent.

COMMISSIONER MATHIAS: 60 percent?

MR. CISEL: Uh-huh.

COMMISSIONER HARVILL: Other questions?

I just have one question. Based upon our experience, problems that developed in other service territories in previous years, one of the findings of our investigations was that utilities had a tendency to take the manufacturer's expected rating for a particular circuit or transformer, what have you, and then, through whatever mechanism, increase that to a higher level.

Are these -- when you say one hundred percent, is that the manufactured recommended limit for that particular circuit, or is it modified by CILCO?

MR. CISEL: Commissioner, if you are asking about the equipment facilities that serve particular customers?

COMMISSIONER HARVILL: Yes.

MR. CISEL: What we do, we run two different scenarios. One is the manufacturer's prescribed limitation. Then we also supply other contingencies which supply temperature as well as humidity factors to it. In either of those two scenarios, we don't exceed 100 percent level on our transmission of the transmission line.

COMMISSIONER HARVILL: Okay. Thank you very much.

If there are no other questions, we are going to move on to Ameren. If they'd come up, I'd appreciate it.

Two gentlemen today from Ameren, Mr. Mark Birk, General Manager ED Technical Services, and Mr. Tom Voss, the Senior Vice President of Energy Delivery.

I will turn things over to you.

MR. BIRK: Thank you.

Good afternoon, Commissioners and Chairman.

I would like to talk directly from the slides, if I may, concerning Ameren.

If you can turn to the first slide please, the Expected Summer Peak Load & Resources, our forecasted 2002 summer peak loads for AmerenCIPS are expected as 3,028 megawatts. Our worse-case scenario is 3,228 megawatts.

For AmerenUE, our expected peak is 600 megawatts. Our worse-case scenario is 728 megawatts.

Our actual to forecasted peak load for 2001, we had a 1 percent error associated with that. And we expect our capability at the time of peak to be approximately 3900 megawatts.

With this, AmerenCIPS has a 29 percent reserve margin expected time of peak. AmerenUE has a 17 and a half percent reserve margin.

We feel that with these reserve margins, we should be adequately able to cover both the expected and worse-case scenarios.

I guess one footnote on the first slide, the AmerenCIPS load includes both the network integrated retail load and wholesale customers that we have capacity obligations to.

Turning to the second slide, new generation has been installed in Ameren's Illinois territory or is expected to be installed. Prior to summer 2002, we expect to have an additional 1,097 megawatts added to the Ameren system.

Of that approximately 1,000 of that, 1,040 of that, is IPP and approximately 60 of that is AmerenUE.

Current active requests for generation connections, and these are NRQ, for the Illinois territory, we have 542 megawatts for 2003, 408 megawatts for 2004.

We currently have no megawatts of requested generation connections for 2005.

We have 5170 megatwatts for 2006.

COMMISSIONER KRETSCHMER: I have a question.

MR. BIRK: Yes.

COMMISSIONER KRETSCHMER: You now have a reserve margin of 29 percent. What in the world are you going to do with all these other kilowatts or megawatts or whatever they are?

MR. BIRK: Prior to --

COMMISSIONER KRETSCHMER: You are at a 60 percent reserve margin?

MR. BIRK: The predominantly -- approximately 90, 95 percent of these will be installed by independent power producers.

COMMISSIONER KRETSCHMER: But you are paying for the hook-up, or are you not paying for the hook-up?

COMMISSIONER HARVILL: They are.

MR. BIRK: The customers are. The IPPs are.

COMMISSIONER KRETSCHMER: Builders.

MR. BIRK: That is exactly correct.

COMMISSIONER KRETSCHMER: Why are they building in Illinois with such rapidity, and are they gas? What are they?

MR. BIRK: The two I am referring to in 2002 are gas.

COMMISSIONER KRETSCHMER: How about the 5100?

MR. BIRK: The 5100, that's 80 percent coal, and that's probably 20 percent gas. I would expect, my personal opinion is that less than 50 percent of that would probably actually be built.

COMMISSIONER KRETSCHMER: None of these are going to be in rate base?

MR. BIRK: I don't believe so.

COMMISSIONER KRETSCHMER: You don't believe so, or you don't know?

MR. BIRK: I don't believe so.
MR. VOSS: They are not Ameren. They won't be in Ameren's rate base.
MR. BIRK: That's correct. They would not be in Ameren's rate base.
MR. VOSS: There is some UE.
MR. BIRK: The AmerenUE facility, that's a 60-megawatt facility.
COMMISSIONER KRETSCHMER: 60 megawatts I can live with but 5100...
MR. BIRK: It's kind of eye opening.
COMMISSIONER HARVILL: Continue.
MR. BIRK: Yes.

Moving onto the next slide, this is an overview of the Ameren transmission system.

We have approximately 5120 circuit miles of transmission from 138 kV through 345 kV and approximately 200 bulk substations.

Ameren is currently interconnected to 27 control areas including TVA, Entergy, SPP, AEP, Cinergy, CE and a number of others.

Ameren's central geographic location

allows power to be transferred any direction within the transmission network's capability.

If you look at the next slide, that kind of gives you an idea of our transmission reach.

Ameren is shown in yellow. Ameren's Direct Connects are shown in dark blue.

So as you can see, we pretty much have a reach both north, south, east and west.

The expected facility loading at summer peak, all lines substations and feeders are expected to be within applicable ratings for both the expected summer peak and worse-case summer peak scenarios.

We definitely have adequate transmission capability. We do not anticipate that there are going to be any transmission constraints on the Ameren system that would prohibit the adequate supply of ARES or RES customers located in the Ameren service territory.

This does not suggest, though, that any ARES customer can necessarily get their supply from any geographic location around the Ameren.

We do have some transmission interfaces that are already heavily subscribed, particularly the ones to the east.

And new generation, new IEPs, et cetera, can positively or negatively impact the transmission loading in various regions.

The next slide, Illinois Transmission Upgrades is 2002. This gives you a rough idea of the type of upgrades and transmission work that we have done.

We plan to have completed by the end of 2002 Coffeen, 345 kV bus and switch upgrades. That's complete.

A New Holland 345 kV substation, a new Xenia 345 kV substation. Those are both IPP connections that are fully reimbursed by the IPP.

Cahokia 138 kV terminal upgrades. Paralleling of Page-Keokuk line with South Quincy-East Qunicy.

This will help alleviate some limitations that others were seeing on our system.

A line upgrade of the Kinmundy-Bluff City

138 kV line. Replacement of two auto transformers at the Newton generating station and some West Frankfort breaker and switch replacements.

This is the -- this is similar to the list that was provided to the ICC staff on March 20th.

Going to the next slide, existing Transmission Service Requests. Basically transmission -- we handle the transmission reservations on a non-discriminatory first-come first-serve basis.

We have approximately 31,000 megawatts months of transmission reserved on the Ameren system for 2002, for summer 2002. That's June, July and August. That is down slightly from last year.

Generation connection requests that are currently NRQ or have been studied, currently we have nine plants on line. The majority of these plants are located in the Illinois territory. We have 8 that are in the engineering and construction phase. We have 13 that are under study or have been studied and are being proceeded with. And we have

43 that were studied but withdrawn by the developer after studies were done.

Transmission concerns that Ameren has. More transmission is required for ARES and RES and generator customers.

Listed below are the hindrances we believe to the building of transmission.

There's planning uncertainties, and some of the planning uncertainties would be IPP. You know, they will make a request on our system. You have to take that into account when you do your planning. Future RTOISO situation. There's also biases that we see across the system. If it's hot to the south, cool to the north, we'll see a bias.

We'll also see east to west biases. So all of those factors have to be taken into account when you do the planning on your system.

There's also regulatory uncertainty both at the FERC and State level.

There's siting issues associated with transmission, both route selection and permanent approvals.

There's resource constraint. By that we mean engineering, planning, design, construction.

Equipment lead times tend to be long. A lot of the equipment associated with these upgrades can require 40 or more week delivery periods. And there's also a cost recovery issue on who's going to -- who essentially pays for the transmission upgrades and the transmission infrastructure.

Moving on to generation issues, when we go to look to generation and what we see is the supply of our load customers, we must maintain appropriate planning reserve margins.

Ameren is currently issued for a 20 percent planning reserve margin, and part of that is due in fact to the potential transmission constraints that could occur, the market price volitility that we had seen in earlier years and we haven't seen as of late, and natural gas or fuel availability and pricing.

Those all go into our mix when we do our planning, make our planning reserve decisions.

We would like to see and maintain a

balanced portfolio of both base load, intermediate and peaking plants.

Associated with that, Ameren feels that we do have a balanced portfolio at this time between nuclear, coal, hydro, gas and oil.

We would like to see that maintained.

We know there is environmental concerns, emissions, nox concerns. There's siting issues associated with plants, and transmission upgrades are frequently required for the addition of plants.

The third major issue we see is the power procurement issue for utilities for 2005 and beyond. Ameren is still evaluating our options concerning that. We have made no final decisions. There's also cost recovery issues associated with that.

Utilities must be able to charge or recover charges that reflect the two costs and risks and obligations.

And onto the last slide which are what we see as suggestions to promote and maintain Illinois reliability, we feel that encourage investment and transmission, we feel new transmission is required to effectively get generation to the load and to foster a competitive environment.

We feel that's the best for Illinois customers. By far we want to have the most transmission available such that they have the best choice from generation suppliers.

We would like to see -- to promote reliability in both the transmission and distribution sector to the balanced use of new infrastructure, in other words, new lines, upgrades to equipment, et cetera, new technologies.

There's tension monitoring devices you can install on transmission lines that gives you more real-time rating.

And processes. We've recently gone through a transmission asset management program where we've actually looked at all of our critical relaying and breakers on both the AmerenUE and AmerenCIPS transmission system, and we've rated them all, and we've come up with a plan to replace the ones we feel are most suspect or the ones that have been our poor performers over the years.

We also feel we need to develop a balanced portfolio generation. Ameren feels we currently have that and we need to maintain that going forward.

We encourage the effective siting of new generation to relieve generation constraints. We feel that we can locate generation in the proper places to help alleviate certain transmission constraints.

And we believe that we need to encourage development of thriving wholesale and retail market.

Are there any questions?

COMMISSIONER HARVILL: Questions from the Commissioners?

COMMISSIONER KRETSCHMER: I have a question.

My understanding, and I think I am correct, is that MAIN requires the 15 percent reserve margin?

MR. BIRK: That is correct.

COMMISSIONER KRETSCHMER: You have got 29 percent --

MR. BIRK: That is correct.

COMMISSIONER KRETSCHMER: -- building.

Why would you need double what MAIN says you should have as far as a reserve margin is concerned?

MR. BIRK: I believe when you look at Ameren as a whole, when you take both AmerenCIPS and AmerenUE into account, our reserve margin looks right around the 20 percent range.

COMMISSIONER KRETSCHMER: Are you saying that you have more generation in Illinois than you have in Missouri?

MR. BIRK: We have more generating -- with regards to reserve requirements, we have more generating capability. Not more as a whole. We have more generating capabilities in Missouri as a whole than Illinois.

COMMISSIONER KRETSCHMER: I am going to ask the same question of all the speakers. I am going -- I didn't ask it before for CILCO because I didn't think of it.

But we are coming into a period where there's tremendous change happening in the industry.

I am asked often by legislators in Illinois that whether or not we are going to see some benefit, monetary benefit, to the citizens of Illinois with restructuring.

I'm not talking about industrial and commercial. They've already seen that.

When are residents, consumers, going to see some price reward for the fact that we have an older market which I have always been assured that a competitive market is the least cost method of supplying everything.

Do you think we are going to see a tremendous drop at the end of the period when the prices are on hold?

MR. VOSS: Certainly the residents of Illinois have already -- residential people already receive --

COMMISSIONER KRETSCHMER: But mandated by legislation. When are we going to see something because the market is now a competitive market? Are we going to see something?

MR. VOSS: It's hard to predict exactly what the competitive market will be in the future, but it's certainly -- that hasn't -- that certainly has had an effect already on what people are paying. Residential people have benefitted --

COMMISSIONER KRETSCHMER: Only because the legislature insisted because every utility fought it very hard.

MR. VOSS: It has encouraged the building of new generation, and it has encouraged the supply. There's been a lot being built in Illinois so that whole law as a whole you have to look at rather than looking at specific instances.

COMMISSIONER KRETSCHMER: That's a specific answer that the prices are going to go down?

MR. BIRK: I do believe that what we have seen in the past -- the past year or two in Illinois is a direct benefit of more generation being located in the state.

When we went through '98 and '99 with capability shortages, we definitely saw the wholesale market prices go to higher levels than we ever thought they could go to.

And with the addition of all the generation, with some of the transmission upgrades that have taken place, the market prices have seemed to settle down. And, you know, while currently we were seeing summer prices in the $60 range for the on-peak market, we have seen most of this year the prices ranging from the 20 to $40 range.

So at that level, it gets very tough to sell into the retail market.

You can sell it to the wholesale just as well as the retail.

MR. VOSS: I certainly think long-term, the competitive market is the best way to go, but there's so many things that influence prices like fuel costs, you know, the supply gas, the supply of oil, environmental restrictions.

Those all play out in the future, but having a competitive market should hold it to lower than it would have been any other way.

MS. KRETSCHMER: So we are told.

COMMISSIONER HARVILL: Are there other questions?

COMMISSIONER HURLEY: I think this question would probably go back to Mr. Cisel.

You didn't comment at all -- I guess you can come up here.

You didn't comment at all on what additions that -- if any, that you are making to T and D projects.

MR. CISEL: On the transmission system, only switch gear and minimal replacement we are doing at this time. There are no circuit upgrades.

On distribution, what we call the worse-case scenario distribution circuits, we are upgrading those circuits with more of the capability to handle a higher load level as well as more secure open stability.

COMMISSIONER HARVILL: Other questions?

COMMISSIONER MATHIAS: I have a question for Ameren.

In the slide that's entitled Transmission Service Requests, you state that 31,000 megawatt months of transmission have been reserved. What's the total that could be reserved for those three months?

MR. BIRK: That basically varies by ATC available transmission capability.

I would have to look at that in more detail to give you that total number across our whole system, and a lot of that is market-driven. It depends where the generation -- where the excess generation is located and where the market is at.

COMMISSIONER MATHIAS: Are you saying that 50 percent of the megawatt months of transmission have been reserved or 90 percent or --

MR. BIRK: I would say across our system, as a whole, certain interfaces are clearly up to 100 percent, but there are a number of other interfaces that would be reserved much less than that. Maybe on the order of 20 percent. So it varies by interconnect.

COMMISSIONER MATHIAS: Then could you go to the slide that's entitled Adequate Transmission Capability and explain what you mean here?

You are saying that Ameren did not -- does not anticipate that there are any transmission constraints on the Ameren system.

MR. BIRK: That is correct.

COMMISSIONER MATHIAS: That would prohibit the adequate supply of ARES or RES customers.

MR. BIRK: That's exactly right.

When I am talking about transmission service requests here, a number of these are point-to-point requests that go through and out of our system.

They are not to provide for native load or load that is located in our system.

We feel that we are definitely able to provide import capability for those.

MR. MATHIAS: To the native?

MR. BIRK: Correct. When you are talking -- when I give the 31,000 megawatt month number, a lot of that is point-to-point service across our system. Not necessarily directed into our system.

MR. MATHIAS: Well, if you go to the second bullet on the Adequate Transmission Capabilities, explain what you are saying there.

MR. BIRK: Basically what that means is that customers -- say a customer now designates that they want to bring -- bring a supply from Cinergy into Ameren and they have that firm. It doesn't necessarily mean that they can elect to bring that from AEP to Ameren for the next month. They can't switch around like that.

Once they -- once they've established their firm transmission paths, we can provide the service into them, but it doesn't mean that they can bounce to different paths because those paths could be tied up by other point-to-point service.

COMMISSIONER MATHIAS: And yet at the same time you believe there are no transmission constraints?

MR. BIRK: No transmission constraints.

An ATC limit is different than a transmission constraint typically.

When I'm talking about a transmission constraint, I am talking about a physical overload on the transmission system.

An ATC limit sometimes can be reflected in someone else's system.

COMMISSIONER MATHIAS: And then in another slide, you state that several items which you suggest to promote and maintain Illinois reliability most of which have to do with nothing related to the Illinois Commerce Commission, I might add, but you state that you encourage the development of a thriving wholesale and retail market.

Do you believe there's a thriving wholesale and retail market?

MR. BIRK: I believe there's a thriving wholesale market right now.

I do not believe there's a thriving retail market at this point.

COMMISSIONER MATHIAS: Do you believe a thriving wholesale market would also be experienced by incumbent utilities other than AmerenUE and CIPS?

MR. BIRK: Can you repeat that question?

COMMISSIONER MATHIAS: Do you believe there's a thriving wholesale market in the Illinois incumbent utility service territories other than those represented by AmerenUE and CIPS?

MR. BIRK: I believe that to be the case.

MR. MATHIAS: I believe Ameren is the only company that there's a thriving wholesale market.

COMMISSIONER KRETSCHMER: Does your -- does your geographic location affect your answer on that?

MR. BIRK: Definitely. Geographic location is a big benefit, both from a transmission standpoint and a generation marketing standpoint. Yes.

COMMISSIONER HARVILL: I just have one question. As we sit here today, almost five years after the signing of the restructuring law here in the State of Illinois, you are currently not a member of a FERC-approved RTO, correct?

MR. BIRK: That's correct.

COMMISSIONER HARVILL: And do you anticipate a day by which you will be in compliance with Illinois statute with regard to joining a FERC-approved RTO?

MR. BIRK: Currently we are in negotiations with both MISO and EJM. We hope for a reply by late May, and we fully intend to comply with that order.

We are still in the negotiation process. I can't give you much more of an answer than that.

COMMISSIONER MATHIAS: Just one other question, and this is perhaps rhetorical which each one of the participants today, but let me ask it in any event.

I take it, Mr. Birk and Mr. Voss, you are here as representives of AmerenUE/CIPS and in that capacity you would represent to the Illinois Commerce Commission that you in the best professional judgement which you have do not anticipate energy summer reliability problems resulting in the AmerenUE/CIPS service territory either from transmission failures or the inability of supply and, therefore, that your retail customers will be well served during the upcoming summer months?

MR. BIRK: That is correct. We expect to serve them very well.

COMMISSIONER MATHIAS: Thank you.

COMMISSIONER HARVILL: Thank you very much.

Moving right along, next we'll hear from Mr. Jack Alexander. Mr. Alexander is the Senior Vice President of MidAmerican Energy Company Supply & Marketing.

Do you have a presentation, Mr. Alexander?

MR. ALEXANDER: I do not have a presentation. I did drop off a disk that can be downloaded and copies can be made of the information.

This is my first time before the Commission so I am learning today. So if there is information that I should have brought, we'll learn today and make sure it's brought --

COMMISSIONER HARVILL: You may get a few bonus points for not having a power-point presentation.

Go ahead.

MR. ALEXANDER: For those in the hearing room who are not familiar with MidAmerican Energy Company, we do serve the western part of Illinois in the counties of Rock Island, Henry and White Side.

We have approximately 85,000 electric customers.

I do want to respond to the concerns that were addressed in the questionnaire from the Commission, and clearly MidAmerican is here today to tell you that our transmission and distribution system is in very good shape, and we do not anticipate any problems in this upcoming summer.

We have invested approximately seven and a half million dollars in the last four years in our transmission system in Illinois, and a lot of that is associated with the construction of the Cordova Energy Center which MidAmerican purchases power from.

We have a contract that goes through 2004, and that's for 250 megawatts. So quite a bit of transmission upgrades were performed to accommodate moving power in and out of Illinois as a result of that plan, and we are also looking at another ten million dollars between now and the end of 2005, and that would be the addition of a new substation in Illinois, some relaying upgrades and some breaker upgrades to improve the system, its ability to function during various operating system scenarios.

We do expect to have enough generation for this summer. Just for your information, we have 4,708 megawatts of capacity available to MidAmerican Energy retail consumers. And we expect this summer's load peak to be 3,924 megawatts which is approximately a 20 percent reserve.

That peak is based on 30-year average of weather that we have experienced in our service territory.

We also went through two other cases, worse-case scenario, which we call a hot weather scenario, and we use weather situations that could occur 30 percent of the time. That gives us a load estimate of 4,107 megawatts, leaving us approximately a 14 percent reserve margin.

And then we look at what is another case that becomes even worse, and that is extreme weather, and that's a weather situation that occurs approximately 5 percent of the time. And in that situation, we are looking at a peak load of 4,302 megawatts or approximately a 9 percent reserve margin.

MidAmerican is looking closely and is actively managing its generation assets.

We currently have participation in a nuclear unit in a Nebraska city, Brownville, Nebraska, Cooper Nuclear Station. That contract expires 2004, and our participation in that purchase power agreement is 379 megawatts.

And to accommodate the loss of that power purchase agreement, MidAmerican has started construction of a combustion turbine and gas-fired combined cycle turbine in DesMoines, Iowa.

That will bring on 540 megawatts. It will be built in phases. The first phase will come on line the spring of 2003. That will give us 350 megawatts. And then the spring of 2005, the second phase comes on line with another 190 megawatts.

And then longer term, MidAmerican is looking at a base load cogenerating plant in Counsel Bluffs, Iowa, that will bring on for MidAmerican somewhere between 350 and 450 additional megawatts.

So MidAmerican pays close attention to its peak load forecast and does anticipate shortages in the future, but steps are well underway to take care of those shortages.

When I look back at the last five to six years of peak load forecasts in our actual experience, we range anywhere from a variance of one percent to three or four percent. So we are very close as far as hitting what we think the forecast will be. It's not an exact science, but we think we've got the right kind of measures in place.

We do not anticipate any plants being scheduled down for maintenance. We've gone through a large number of maintenance upgrades and overhauls this spring. Some of our plants are just wrapping up their last couple weeks of spring outages so when we get ready for summer, we expect to have plants on line and ready to meet our customers' needs.

I believe those are the comments that I have and would open it up for questions from the Commissioners.

COMMISSIONER HARVILL: Are there questions from the Commissioners?

Commissioner Squires?

COMMISSIONER SQUIRES: You mentioned that you'll be having shortages in the future. Are you talking about, what -- a particular month, or are you talking about a year?

MR. ALEXANDER: We are talking about the 2005, 2006 time frame where we need power.

That's why -- 2004 we have something like six megawatts of additional reserve. That's why we need to bring on the Greater DesMoines Energy Center, and that's coming on the spring of 2003. So that will give us enough reserve margin to make it through that period.

COMMISSIONER SQUIRES: You said in 2006 you should be having an outage. How would you rectify that?

MR. ALEXANDER: Right now we are looking at other options. We are looking at a purchase power agreement to fill the void before the coal plant comes on line in 2007. But we don't anticipate any serious problems with that.

Clearly we'll keep the Commission advised as to what our forecasts look like.

COMMISSIONER KRETSCHMER: What do you foresee in the near-term future after the law -- our law goes out of effect and the market is open?

MR. ALEXANDER: I have been thinking about it, and it's a confusing subject for me in the sense that part of our operations is in a regulated environment that is not open to competition and then the other part of our operation is in an environment that very much desires to have an effective competitive electricity market, and we've been very active in that.

And we think that once the transition period goes by the way side, the transition charges, that will give a more realistic look at what the market is and what the opportunities are, but I wouldn't be honest if I said that it's easy right now. It's very challenging to try to make it work, but we do believe that competition will be bringing benefits to consumers, and we are very supportive of it. Hopefully we can make progress in Illinois. We are learning a lot from this experience.

COMMISSIONER KRETSCHMER: You are going to sever your connection with the nuclear plant in Nebraska, I believe.

My understanding is that plant is going to ask for an extension of their life at the NRC. Do you foresee the possibility of again becoming a user from that nuclear plant?

MR. ALEXANDER: You raise some very interesting questions.

First of all, we have notified Nebraska Public Power District that it is not our intent to renew our purchase power agreement beyond 2004, but we have not officially told them that.

There is uncertainty as we speak as to whether or not Cooper will go beyond 2004.

And our team has had discussions with the NPPD Board of Directors as of last week and they have not yet decided, and they need to look at a number of options for NPPD and Nebraska to decide if they go forward.

As this Commission knows, that plant has some issues with the NRC, and I've gone down to Dallas to talk to the NRC, Alice Merchaw (phonetic), the region administrator, to understand what this process is going to be this summer when the NRC comes in to do an inspection.

We've evaluated the risk and clearly to MidAmerican's retail customers, there are risks, but after talking to the NRC, I'm convinced Cooper is a safe plant.

The issues that they have to address are minor, but they do need to have a very effective tactical improvement plan that consistently is executed. And that will help mitigate the risk.

The challenge for NPPD is, to go through the NRC inspection and to implement the tactical improvement plan, it will cost dollars, and it's going to be slow, it's going to be costly and it's going to have a lot of NRC oversight.

That doesn't help its position in the market because it's already a very expensive plant.

Unlike our participation and our joint ownership in the Quad City 1 and 2 units where we have seen a tremendous turnaround in performance over the past few years.

So we would love to see Cooper get to the level of performance where the Quad City units are, but that's going to be a challenge. So at this point in time, it's our intention not to continue.

COMMISSIONER KRETSCHMER: Thank you.

COMMISSIONER HARVILL: Are there other questions?

If not, thank you very much.

My wife works with individuals with various forms of dementia, and I fully believe it's contagious. So, Shawn, if you forgive me, I've forgotten how to pronounce your last name.

MR. SCHUKAR: Schukar.

COMMISSIONER HARVILL: Schukar. Thank you.

Next we'll hear from Mr. Shawn Schukar who is Vice President of Energy Supply Management for Illinois Power.

And with that, I will turn things over to you.

MR. SCHUKAR: Good afternoon. Chairman and Commissioners, I would like to thank you for the opportunity to present Illinois Power's preparedness for summer reliability. I will try to keep this brief. And we'll go from the presentation that you have.

On the first page I think I would first like to focus on how our system is put together and the ability to supply loads connected up to our system. We have nine interconnections, and they are strong interconnections to the west with Ameren, to the north with ComEd, to the east with America Electric Power and then to the south with TBA. So we reach into a lot of markets which gives us a lot of capabilities.

There are no elements on Illinois Power's transmission system or distribution system which would limit the ability to bring power into our system to serve load.

Our simultaneous import -- and just to make certain that everybody understands, simultaneous import is a snapshot look at the system -- we take into account the models that have been built.

So whatever transmission was already reserved on the system, any generation that's on is taken into account when we do that. Based on those studies, we are able to bring in 3,226 megawatts into our system.

That's about 75 percent of the total connected loads on our system.

Additionally we have about 1,228

megawatts of non-affiliated generation which is again about 28 percent. And of the load that is served in our territory, there is over 1,000 megawatts of network resources that are utilized to serve -- external network resources that are utilized to serve load inside of Illinois Power.

So there are resources that come from ComEd's territory, Ameren's territory, PVA, Electric Energy Incorporated. Okay?

Onto the next page, from the system performance, last year there was no firm curtailments affecting transmission facilities on Illinois Power's system.

There was 148 Level 2 TLRs within -- a Level 2 TLR or higher is a TLR that affects a transaction. So if there's a schedule adjustment as a result of a transmission loading relief, that's what we are counting here.

Of the 148 that were within MAIN, none were attributable to Illinois Power facilities during the summer period.

For the full year, there were 466 in the

MAIN region. Of those, 6 TLRs occurred or were as a result of Illinois Power facilities.

Those were all the result of the Coffeen Roxford facility. It was when -- before we upgraded the facility or during the period of time where we were upgrading the facility rating.

Since that time we have had no TLRs as a result of that facility.

The next page, there's no expected overloads in our transition or sub-transmission system during normal conditions.

We do have two sub-transmission facilities that would slightly exceed their normal rating if we went to a worse-case scenario.

Our worse-case scenario is the hottest temperature in the last 20 years, is what we utilize, and for both these facilities, it occurs both with the hottest temperature, and they are in a region where we have grain drying load. So it's also -- it's the hottest temperature plus all the drain -- crane -- grain drying load being on at the same time. So that in both facilities we do not expect this to occur.

One of the things that we have incorporated in the last year is an asset management practice where we focus our capital expenditures across the business units. Before we did transmission, distribution, gas. We did them all kind of separate.

Now we've integrated it all into one process so that we are able to look at reliability of the system, the throughput of the system and put the dollars where we gain the best improvement on the system for the dollars that we spend.

We are planning to upgrade several areas this year. We are upgrading the Manuth (phonetic) Boulevard transformer, East Belleville transformer, some breakers at Oriana and then also continuing with our storm structures program.

These are for both throughput and reliability and will improve the performance of our system.

On the next page, we'll get to the resource requirements. Illinois Power's resource projections for this year for the retail load at Illinois Power is 3,258 megawatts.

Our supply arrangement is for 3,875 megawatts.

Of that firm, 2,945 are from Dynergy. I would like to point out while we have contracted with Dynergy for 2,945, that's what we told them we would need. Based on PPA, they are responsible for 3,800 megawatts. So there's a lot more available in the instance where load could come in higher.

But what we've told them we are going to require is 2,945 megawatts.

Onto the next page, the forecasted load in our control area is 4,003 megawatts which is a little different than what Illinois Power is required to serve.

That would include wholesale customers and retail customers making a choice.

And then the last one is the transmission system connected load.

We have some load that is connected up to our transmission system, but it is dynamically scheduled into another control area.

So the 4,276 is from a wires prospective of how much load we would have to serve for the summer of 2000.

Of that load that has to be served, there is 5,877 megawatts of generation internal to our control area. That would be available to serve that. So it's easy to see there's excess generation in our area to supply not only Illinois Power load requirement but the load to other wholesale and retail customers.

The next slide shows our base forecast and our worse-case forecast. Again, the worse-case forecast is based on the highest temperature in 20 years.

For the base forecast, we show 19 percent reserve.

One of the things I would like to highlight, though, is currently we are evaluating our forecast because of retail choice. Some customers have given indication to us they may return to Illinois Power for commodity supply, and as we evaluate that, we'll also evaluate our resources.

In the worse case, we would still maintain 11 percent reserve for the scenario outline.

The next couple graphs are rather busy, but what we wanted to show is that, in the past and in the future, we plan on maintaining 17 percent reserve or around 17 percent reserve requirement.

When you look back in history, there has been times where it has become very low whether it was a result of the actual resource being off line in some cases or warmer than normal weather, whatever, the reserve margins will swing, but in all cases we were able to meet our requirements.

On the next slide is the indication of Illinois Power actual load versus our forecasted load. As you can see, over the years it's ranged from minus 6 percent to plus 7 percent.

One thing to recognize in this graph is that it does not include an adjustment for interruptible load. So if we add interruptible load on, it would not back out to line up the forecast which would cause the years where the forecast was higher to be somewhat -- the actual to be somewhat lower than what it was.

I will go ahead and skip the next page then. Just to remind everybody that Illinois Power does have several rates that encourage time of use, off-peak usage. We have the real-time pricing where customers get hourly price signals and they are able to react to the price of energy in the marketplace.

We have several interruptible rates that are available to -- that our customers have, and finally we have a load reduction pricing experiment for our customers that if the prices get high in the market, we would give that signal to the customers and they can voluntarily reduce their load which is about 75 megawatts of total load.

All in all, when you look at other transmission and distribution and generation resources we have, Illinois Power feels that we are in a very strong position for the summer.

COMMISSIONER HARVILL: Questions from the

Commissioners?

COMMISSIONER KRETSCHMER: I will ask my question. What do you think is going to happen at the so-called transmission period?

MR. SCHUKAR: I think competition brings two things to customers. One is it presents alternate supply which should theoretically reduce the overall cost of the market price.

The question I think that we have to sometimes answer is, by having competition out there, does it provide a lower price than if we had not had competition, and because we are kind in the middle of that, you can't say would the prices have stayed exactly the same if we had remained at a regulatory environment versus where we are at with the competitive environment.

I truly believe that competition does provide a benefit because, with people completing, that causes people to be more efficient with the generation and utilization of the system which will ultimately drive down the prices.

I think the second thing competition does is it provides alternate types of offerings to the customers, things that we may not have thought about in a regulated environment because we tend to think about the same way of doing things.

COMMISSIONER KRETSCHMER: Okay. Thank you.

COMMISSIONER HARVILL: Mr. Chairman.

COMMISSIONER MATHIAS: Is there any consideration being given by Illinois Power to amend its open access transmission tariffs as far as the penalties for over- or underdelivery of retail customers?

MR. SCHUKAR: We currently don't have any plans to change our open access transmission tariff, and part of that is because once we go into the RTO world, we will then be under the RTO's open access tariff.

COMMISSIONER MATHIAS: So the imbalance provisions that are now in effect at least for the forseeable future, until such event occurs, would remain the same?

MR. SCHUKAR: That is correct.

COMMISSIONER MATHIAS: What do you see with regards to summer prices?

Mr. Cisel has indicated that he's in the 60 to $70 range delivered. Is that your opinion as well?

MR. SCHUKAR: That is consistent with our experience, yes.

COMMISSIONER MATHIAS: And then the rhetorical question perhaps, and that is that you are here as a representative and officer of Illinois Power and in such capacity do you believe that there will be adequate supply for your retail and wholesale customers and that you'll not have a significant restraint in the transmission -- restraint or failure in the transmission and distribution system that would result in an interruption of power to either wholesale or your retail customers during the summer months?

MR. SCHUKAR: Yes.

COMMISSIONER MATHIAS: Thank you.

COMMISSIONER HARVILL: Other questions?

COMMISSIONER HURLEY: Shawn, you didn't mention any transmission distribution projects that are imminent right now.

Do you have anything going on?

MR. SCHUKAR: Yes. The Manuth Boulevard that I mentioned and Belleville to Porter Road, and then we are adding something in the Galesburg area.

COMMISSIONER HURLEY: Thank you.

COMMISSIONER HARVILL: I know we discussed this off line, but would you care to share with us your plans for becoming compliant with the Illinois Public Utility Act as it relates to joining a FERC-approved RTO?

MR. SCHUKAR: Can I copy what Mr. Birk said?

COMMISSIONER HARVILL: If you like.

MR. SCHUKAR: In general, Illinois Power is in negotiations with the alliance and PJM and Midwest ISO, and we will comply with FERC's requirement by late May that will tell them what RTO we will be joining.

COMMISSIONER HARVILL: Thank you.

If there are no other questions, we'll move on.

Lastly we have Ms. Arlene Juracek from Commonwealth Edison. She is Vice President of

Regulatory Strategic Services.

Are you getting a title change? Every time you come, it seems like it's changed.

MS. JURACEK: It's been that for about a year.

COMMISSIONER HARVILL: That being said, we are going to hear from Arlene today and walk through ComEd's forecast for this summer and then hear plans to meet their load requirements.

With that, I will turn things over to you.

MS. JURACEK: Thank you.

And joining me today is Dr. Jim Williams who's our vice president of project and contract management at ComEd. He works in the operations side, and while I will be giving the presentation, Jim will be available to answer any specific questions on transmission and distribution projects.

We also had the privilege of engaging in a discussion with you about a month ago, myself and my two colleagues, Bruce Renwin and Wayne Schnitzer, about the longer term outlook for both generation and transmission and its capability to support a sustainable competitive marketplace.

So some of what my colleagues from the other utilities spoke of today we addressed in that earlier presentation.

Today I will focus more on summer of 2002 and meeting our reserve requirements for the summer.

In a nutshell, our story is fairly consistent across the state. Both ComEd and Exelon generation, in the case of Northern Illinois, will be able to comfortably meet the energy demands of the ComEd customers.

And based on mean expected load forecast and the designated resources to serve ComEd load, the MAIN audit was just completed, and ComEd has an 18 percent reserve margin which is comfortably above the 15 percent MAIN recommendation.

We also know that, based on the resources that are available to us, we can very comfortably meet not only the expected load with its 18 percent reserve margin by also our high expected load scenario.

If we go to the next line with the bar

chart, you can see the relationship of both of the historical peaks and our 50/50 peak in the high expected load.

The mean expected load for the control area for ComEd is 21,900 megawatts.

And what that means is you have an equal chance of a load actually being less than that or greater than that depending on actual summer and economic conditions.

For resource planning purposes, we calculated a high expected load, and this is an 80/20 load. It's 23,100 megawatts.

And what this means is there's a 20 percent chance that the actual load will be higher than this load.

We have traditionally, as an integrated utility under MAIN, always done a 50/50 load and then procured resources to meet a reserve margin of 15 to 20 percent above that.

Where we are now a purchasing utility, we like to provide a resource target to our supplier, in this case Exelon Generation. So we've calculated this high expected load planning target for them to procure resources against.

It is this procurement plan to meet that high expected load that has resulted in the MAIN criteria of 18 percent being met.

We also looked to see whether or not weather is forecasted to be cooler than normal or hotter than normal, and this year the weather man is even less useful than they usually are, and they're basically saying there's an equal chance of being hotter or cooler or just plain average this summer.

So we don't have a high expectation of exceeding the 80/20 load, but as you see, there are sufficient resources available should the load exceed 23,100.

The next line just goes through quickly our portfolio of generation resources.

We have about 23,200 megawatts of generation resources designated to serve the ComEd control area load. And you can see the breakdown here between the Exelon-owned nuclear generation, the Midwest Gen resources. There's 1700 megawatts of Dominion-owned generation, which would be our former Kincaid and State Line stations, and then finally there are 2400 megawatts of additional Exelon-owned or contracted-for iron-in-the-ground resources.

So our portfolio is diverse with respect to supply source. It comes from a number of different areas, and it's also sufficient again to meet that 23,100 megawatt planning target.

The next line quickly takes you through the MAIN reserve margin calculation, and essentially we start with the 21,900.

ComEd has some wholesale sales responsibility principally Batavia, Naperville and St. Charles. We have a contract with Aliant Energy, and another with the Illinois Municipal Electric Agency.

And so those five total 175 megawatts.

We subtract from that a load in our control area that we expect to be served by retail electric suppliers, and then we also subtract our interruptible load.

And our expected peak load for MAIN reserve margin calculations is 119,625 megawatts.

So this is the load that ComEd would serve either under bundled rates or underexpected conditions on the power purchase option. And then we go through that reserve margin. We compare the 19,652 with the 23,200 megawatts of designated resources, and that's where we get our 18 percent reserve margin.

So in summary, we have Exelon-owned or contracted resources sufficient to meet our high expected load scenario. We have expectations of RES supply load and ComEd curtailments that would reduce our load by about 2500 megawatts. And in addition, there are a variety of other resources available to Exelon Generation, our supplier, to meet our load which would be additional Exelon resources that are not committed to the ComEd load, newly constructed IPPs in Illinois, and, in our last presentation, we outlined the significant number of megawatts that have been placed in service over the last few years, and then finally additional spot purchases from the regional market.

This last bullet is really important because in an effort to be conservative and address reliability concerns over the last two years, we've tended to focus on a 90/10 planning target rather than an 80/20 planning target.

We believe we can comfortably and cost effectively work to an 80/20 target this year precisely because there are so many additional resources available which are uncommitted. Much of the IPP resources, something on the order of 6,000 megawatts, are not committed to long-term contracts and would be available for spot purchases.

COMMISSIONER HARVILL: Just to stop you on that point, I wasn't aware we had a functioning regional market for spot purchases.

Could you expand upon that a little bit and maybe describe the robustness of that particular market that you would be obtaining your service from?

MS. JURACEK: It's not capitalized so it's not "The Regional Market," and certainly our hope with all the other utilities is to be in a functional regional transmission organization by the end of the year because, as they are evolving they, in fact, will be, it appears, the operators of the day-ahead and real-time spot markets. So we are not there yet in terms of having those markets.

There are spot purchases that are made on a bilateral basis, and that is what our power traders spend a great deal of their energies doing during those hot summer days.

COMMISSIONER HARVILL: Would you characterize that bilateral spot market as a robust market in that it is adequate to actually meet your supplies?

MS. JURACEK: I believe it is. I believe it is.

When ComEd operated its own wholesale training organization, I was able to witness that operation and it was very robust, very active and, again, given the number of resource that are available, we believe that we can meet our needs through those spot purchases.

COMMISSIONER HARVILL: Okay. Thank you.

MS. JURACEK: If we turn to the delivery system, we have a good message here as well, and that is that under both the expected and worse-case summer peak scenarios, there are no transmission elements or substations expected to be loaded above 100 percent of their respective ratings.

If we look at the distribution feeders under worse-case loading, none will be loaded greater than 105 percent with the completion of certain remedial actions which are planned for this summer, and ComEd continues to increase our transition and distribution capacity and reliability through these types of targeted projects.

The next pages take us into a little more detail.

On distribution substations, we do our planning on a 90/10 scenario for a distribution planning. So it's a more strict criteria that we are using this year for our resource capacity planning.

And essentially, we are building three new substations in the South Loop, New Lenox and Orland Park which are going to facilitate the distribution system robustness for this summer. We are increasing capacity at 14 substations, and we are replacing transformers with larger ones at 3 substations.

COMMISSIONER HARVILL: What are the time lines on construction of those three new substations?

MS. JURACEK: I turn that to Jim.

COMMISSIONER HARVILL: If you could use the microphone.

MR. WILLIAMS: These will be in service by June 1.

COMMISSIONER SQUIRES: Of this year?

MR. WILLIAMS: 2002.

COMMISSIONER HARVILL: With the construction of the new South Loop Substation, will that address some of the problems that have developed in recent years with regard to the Jefferson Street Substation?

MR. WILLIAMS: There's another substation being equipped that's a transmission substation, Dekoven, that will back up the Jefferson Street Station, and I believe that will be on the next slide.

COMMISSIONER HARVILL: Okay. Thank you.

MS. JURACEK: It is the next slide, as we turn to Transmission System Projects for 2002.

Again we do that planning on a 90/10 basis, and we are increasing transmission system capacity and reliability by adding to the substation at Dekoven, upgrading Silver Lake, and then you can see we are doing additional increasing of capacity at two 345 kV circuits and six 138 kV circuits through various improvements.

COMMISSIONER HARVILL: The time line on the new substation, the Dekoven substation?

MR. WILLIAMS: Dekoven is carrying load presently, and it will be completely finished in mid June.

COMMISSIONER HARVILL: Thank you.

MS. JURACEK: So on our last slide, we simply summarize that our load serving obligations will be met through our full requirements contract with Exelon Generation.

We have forecasted both our expected and worse-case loads and worked with Exelon Generation to insure that we have sufficient identified resources. Our reserve margin exceeds the MAIN guidelines, and we are doing a very good job I think of increasing our loading capabilities on both our distribution and transmission substations.

As I indicated, the transmission substations are at -- none of them will exceed the 100 percent loading, and the transmission (sic), none will exceed 105.

COMMISSIONER HARVILL: Before I turn to questions, going to your Slide No. 8 where you talk about the ratings of your particular transmission distribution facilities, as I noted earlier, in previous years, it was noted that it was common practice for Commonwealth Edison to take the manufacturer's rating and then increase it above that and in some cases actually exceed that increased level.

Can you talk a little bit about what the actual ratings are and how those are derived, whether they are manufacturer's ratings or they are your modified ratings?

MR. WILLIAMS: You are getting beyond my expertise, but it's my understanding that we are using the manufacturer's ratings and we are using these extreme summer conditions to compare that against.

COMMISSIONER HARVILL: So we shouldn't see any situations where we have the Chicago Fire Department spraying down transformers and such?

MR. WILLIAMS: Not again.

COMMISSIONER HARVILL: Other questions?

COMMISSIONER KRETSCHMER: I will ask my normal question I have been asking and which Mr. Cisel got away without an answer so I will ask them to give me a forecast.

COMMISSIONER HARVILL: I am not sure you want Scott to respond to that.

COMMISSIONER KRETSCHMER: What do you think about --

MS. JURACEK: What I think is that, if we are all successful, and that means both at the retail level, wholesale level, the RTO level, no one can predict whether prices will be higher or lower than they are today, but what we'll know is that they are more efficiently determined and that resources are more efficiently allocated from a sociatal perspective.

The regulator has done a fine job of replacing competition in the past, but what we found is that it often turns economic pricing on its head. Prices went up when you added capacity.

So when you had a lot of resources available, prices went up, and as capacity became tighter, prices either stayed the same or went down because of depreciation. So there was -- the supply and demand curve was turned on its head with respect to the pricing access.

And what we see in a competitive market is that supply and demand forces affect your prices and create a market pull for new resources to come into the marketplace.

If we are successful in having efficient markets through the RTOs and through the work of all of the state holders, I think what we can avoid is that boom bus cycle that creates the extreme variability.

You'll need variability in prices obviously to incent the appropriate resources, but we can temper that variability by creating markets that are more efficient.

COMMISSIONER KRETSCHMER: I love the way economists use the word efficient instead of giving me a direct answer. Thank you.

MS. JURACEK: You're welcome.

COMMISSIONER HARVILL: Was that a step up from engineer to economist?

COMMISSIONER KRETSCHMER: I hear Terry say, this is going to be more efficient.

What does efficient mean? I've looked it up in the dictionary. It doesn't have anything to do with pricing. Not in the dictionary. Thank you.

COMMISSIONER HARVILL: Are there other questions from the Commissioners?

COMMISSIONER MATHIAS: I don't want to be argumentative, and, therefore, I will not ask the court reporter to read the answer that you provided to Commissioner Kretschmer's question, but I will review it carefully when the transcript comes out.

Are you saying that we have a competitive market now?

MS. JURACEK: I didn't say that.

I said, if we all work together through this transition -- and that transition is going to take several more years when you consider that we still have to join a functioning RTO, either PJM or MYSO, we have to get those real-time and day-ahead markets functioning to do the infrastructure, the software, the programing, get the market mechanisms up and running is going to take several years, and I believe I saw a copy of the letter that the MYSO sent to the Commissioners which indicated that 2005 might be an expected time line for them to be working with the PJM designer to have these types of markets fully up and functioning.

So we need to keep our eye on the end point which is somewhere between 2005, 2007 and keep working towards that end point hopefully sooner rather than later.

COMMISSIONER MATHIAS: Are you saying we could have a competitive market -- excuse me.

Are you saying we could have an efficient market without having a competitive market?

MS. JURACEK: I think efficient markets are competitive, and the question is how are you defining the market.

There are certainly segments of activity out there where rational decisions are being made and choices are being offered.

Can you argue that that is competitive in that section or that segment of the market? And it very well may be and it may, in fact, be efficient for that segment.

Before we see this filter all the way down to the retail residential market, I think it's going to be a number of years however.

COMMISSIONER MATHIAS: I just would note I am not going to pursue this line of questioning since this is not really the topic of our discussion today, but I do have a couple questions related to summer reliability.

What has been undertaken with regard to ComEd's efforts to appropriately test the reliability of underground cables which in the past summers have frequently failed in very hot weather durations?

Is there any way to predict the failure of these heavy duty underground cables which have failed in summer '98, '99 and thus so in 2000?

MR. WILLIAMS: Again, that's not my particular area of expertise, but I know that we are working on ways to test the cables you refer to, and we are insuring that they are not overloaded as well.

We are furthermore -- as a part of our reliability upgrades in the city, we are providing alternate supplies so that it's more of a network system as opposed to a hub and spoke system, and if one cable fails, we may not lose customers.

COMMISSIONER MATHIAS: Let me ask the question again: Has there been any improvement in the technology which would allow you to predict the failure of underground cables?

MR. WILLIAMS: I'll have to get back to you on that. I know we've investigated at least a couple of those technologies. I don't know the results.

COMMISSIONER MATHIAS: With regards to the scenarios which you are using, has there been any change in the planning criteria which you use to determine or to define the expected scenario as against the worse-case scenario?

MS. JURACEK: We still use the same type of modeling. It's a combination of econometric modeling and end-use modeling, and we then get to that expected peak load.

We work with historical weather information and, to my knowledge, there's been no change in that mean case.

COMMISSIONER MATHIAS: In other words, you've not shortened the duration in which you look at the prior weather conditions from five years -- from -- to five years from ten years.

MS. JURACEK: I think we look at the longer term. We look at the 15 years. We look at 5 years. But the modeling, the econometric modeling, is built on a longer-term historical period and the weather data are put in for that longer period.

COMMISSIONER MATHIAS: So is your answer there has been no change in the planning criteria?

MS. JURACEK: Not that I'm aware of. We'll take a look at that. If there's been a change, we'll report that back to you.

COMMISSIONER MATHIAS: In your worse-case scenario, how many days of X degree temperature do you anticipate? As you recall, in 1998 and 1999, we had extensive number of days of over 90 degree temperature.

MS. JURACEK: It's really a combination of variables.

Our modeling looks at temperature, humidity index and temperature alone both in the hour of the peak and the hours leading up to the peak and in the several days leading up to the peak.

So you would do this statistically and look at the statistical distribution of the information for all of those variables, and then you would run your models and then get the statistical distribution of the results.

COMMISSIONER MATHIAS: And how many -- let me ask the question in layman's terms -- are you predicting in your worse-case scenario 5 days in which the temperature exceeds 95 degrees, or are you looking at 10 days within which the temperature exceeds 95 degrees?

And as you recall, the problem which we've had in the past with Commonwealth Edison and which I know you have attempted to address is the failure of underground tape cables which is largely brought about because of excessive extreme temperatures over a long duration of time.

MS. JURACEK: I have been addressing supply-side peak load forecasting.

What I hear your question addressing is how do we do our distribution planning, and I'll turn that over to Jim.

MR. WILLIAMS: I don't know the number of days over 90 degrees.

The criteria are that it would be the worse summer in a ten-year period, would be the lay criteria.

MS. JURACEK: It's really a statistical permutation of all these variable. It is hard to say it means 10 days over 90 degrees.

COMMISSIONER MATHIAS: And when does summer begin as far as Commonwealth Edison is concerned?

I understand originally it began in June and ended sometime in September and then was moved to beginning May 15th for planning purposes.

Where are you today?

MS. JURACEK: Well, summer peak very rarely occurs on May 15th.

COMMISSIONER MATHIAS: I am sorry. For planning purposes and maintenance of plant and having plant available, when does summer begin?

When do you have your capacity available for your summer scenarios?

MS. JURACEK: Essentially June 1st on the supply side.

COMMISSIONER MATHIAS: So that's been moved back 15 days. It was May 15th when you testified two years ago, when Commonwealth Edison testified, not you.

MR. WILLIAMS: For the purposes of the infrastructure, having the infrastructure in shape for summertime phenomenon, we target completion of all our summer work by June 1st. However, as a practical matter, we have scheduled probably 90 percent of it to be complete by May 15th.

That gives us a couple of weeks to accommodate bad weather or other contingencies. So of the 402 summer critical projects that we are executing, by far most of them will be complete by May 15.

COMMISSIONER MATHIAS: Does the summer end from the layman's term at the end of August or the end of September?

In other words, do you begin your maintenance projects at the conclusion of September or the middle of October, expecting that you'll not experience the summer peak or the worse-case scenario?

MS. JURACEK: For supply-side, summer is June, July, August and September.

For distribution and transmission, I will turn that to Jim, but I don't believe in my experience that I have been here almost 30 years, we've never had a peak after September or the first week in September really.

MR. WILLIAMS: Right. We schedule maintenance to go back to a nonsummer schedule in early September, but then we have the flexibility to change things if we were to experience high temperature.

COMMISSIONER MATHIAS: And then the rhetorical question, I guess, and that is, I take it, Ms. Juracek, you are here as an officer of Commonwealth Edison. You represent that your company will have adequate supply or your retail and wholesale customers this summer and they will not have significant transmission or distribution constraints which would result in interruption of power for either wholesale or retail customers?

MS. JURACEK: Yes.

COMMISSIONER MATHIAS: Thank you.

COMMISSIONER HARVILL: Are there other questions?

I will ask my final question. You touched on it briefly with regard to joining an RTO.

I don't know whether you would care to elaborate on Commonwealth Edison's plans or the events that occurred today with regard to AEP.

I will ask it the same way the chairman did. Will you be in compliance with the FERC and the Illinois Public Utility Act with regard to belonging to a FERC-approved RTO by March of 1998?

MS. JURACEK: I believe we were back then, but it is ComEd's goal to be a member of a functioning RTO by the end of this year. The events of today I presumed you are referring to the announcement by PJM that they have a memorandum of understanding with AEP for the AEP West Utilities to be a member of PJM West.

That's an MOU, as I understand it, and they have significant details that are still to be worked out, but they've indicated through this MOU a partnership to get that done expeditiously.

COMMISSIONER HARVILL: So it's your intent to comply with the latest FERC order within a period of 30 days and indicate to the FERC?

MS. JURACEK: Yes, and I think the events of today certainly are going to clear everybody in this room's thought process in terms of which way they may turn.

I don't know what the outcome will be.

COMMISSIONER HARVILL: Thank you.

Are there any other questions?

COMMISSIONER KRETSCHMER: Should we give CILCO the opportunity to give us an anwer about forecasting --

COMMISSIONER HARVILL: Mr. Cisel, would you like to come up?

COMMISSIONER KRETSCHMER: I know he's anxious to give us the new information.

MR. CISEL: The question you want me to respond to is what, Commissioner?

COMMISSIONER KRETSCHMER: What do you anticipate happening to the price of electricity for residential customers after the end of the transition period 2005, 2006, somewhere through there?

MR. CISEL: From a marketer's point of view today, and we are very active in providing physical supply to commercial industrial customers, I think we collectively know in this room about the process to determine whether or not there are strong economics to encourage a competitive market.

I can tell you from a marketer's point of view and looking particular at the residential customers segment, when we've analyzed the opportunities on the best-case scenario today, it would take a marketer four to five years to just cover the cost in serving a residential customer.

And when you couple that with credit risk and imbalance risk, certainly today, unless it's a lost leader activity for a marketer, the residential market segment will not be attractive to any marketer.

The only residential segment that I'm aware of today that has any interest at all by a marketer and where you are considering this is where an employer is considering to provide incentives to their employees and to do a collective purchase of both industrial or nonresidential load along with the employee load which would be residential.

That is the only feasible market that I'm aware of today and probably the only feasible market for that segment for several years to come.

COMMISSIONER KRETSCHMER: Very good. Thank you.

CHAIRMAN MATHIAS: As you know, Mr. Cisel and if you are in the marketing area, you would be much more aware of this than I -- CILCO was very aggressive in entering into special contracts prior to the time that a customer could select to receive supply from a third party.

I believe this high percentage of your business and commercial customers were specifically sought out by CILCO to enter into these types of contracts, and the electric restructuring law amendment which is pending now would allow you to continue those special contracts in force until 1996 -- 2006.

Is the -- is it the intent of CILCO to continue to aggressively pursue the commercial and industrial customers with special contracts in the future just as you did in the past?

MR. CISEL: Certainly that is the plan.

When there are mutual benefits for the customer and the company, we will pursue that. And we'll be able to pursue that as we intend to apply a function of a separate utility later on this month.

COMMISSIONER MATHIAS: Do you think that is an effort that would aggressively promote competition during this transition period?

MR. CISEL: It certainly enables the customer to have an option. The option to weigh the benefits to stay with CILCO and supply its services or seek another alternative supplier.

Currently today there are no active alternative suppliers or marketers trying to win the business of any retail customer in our service territory.

COMMISSIONER MATHIAS: Thank you.

COMMISSIONER HARVILL: If there are no other questions, I would like to thank the panels on behalf of the Commissioners, and we are adjourned.